Prospects for Participation of Methane Sectors in Emissions Trading Programs in California

October 14, 2005

Contact Information:

Center for Clean Air Policy
750 First Street, NE, Suite 940
Washington, DC 20002
202-408-9260
202-408-8896 (fax)
www.ccap.org

Acknowledgements

The primary author of this paper was Daniel E. Klein of Twenty-First Strategies, LLC. Stacey Davis, a Senior Policy Analyst and Manager of State Climate and Stationary Source Policy, and Matthew Ogonowski, a Policy Analyst at the Center for Clean Air Policy, provided substantive and editorial comments. Matthew Ogonowski also drafted sections on non-trading policy options for reducing emissions from manure management. This paper was prepared under the direction of Edward A. Helme, President of the Center for Clean Air Policy. We also acknowledge Cynthia Cory of the California Farm Bureau Federation and the other California stakeholders who provided comments on our analysis.

We are grateful for the support of our California sponsors, including The Energy Foundation, the Richard and Rhoda Goldman Fund, and the California Energy Commission.

Edfnjurxqg

This memo presents an analysis of the three major methane-emitting sectors in California (natural gas systems, landfills and manure management) and their suitability for emissions trading. In the case of manure management, we also review other policy alternatives.[1]

This analysis builds upon the larger analysis undertaken for CCAP on methane emissions trading. The most recent version (August 2005) of that report – *Suitability of Methane Sources for Greenhouse Gas Emissions Trading* – has been updated to be consistent with the additional analysis conducted here.

Parts of this analysis also draw heavily upon emissions inventories and economic analyses prepared by the California Energy Commission and by ICF Consulting:

- California Energy Commission, Public Interest Energy Research (PIER), *Inventory of California Greenhouse Gas Emissions and Sinks: 1990 to 2002 Update*, Publication #CEC-600-2005-025, June 2005, http://www.energy.ca.gov/2005publications/CEC-600-2005-025/CEC-600-2005-025.PDF .
- California Energy Commission, Public Interest Energy Research (PIER), *Inventory of California Greenhouse Gas Emissions and Sinks: 1990-1999*, Publication #600-02-001F, November 2002, http://www.energy.ca.gov/reports/600-02-001F/index.html.
- ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California*, draft report prepared for the California Energy Commission, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

There are differences between the CEC and ICF reports. Additionally, both the CEC and ICF reports show significant differences in emissions estimates and forecasts relative to earlier and/or draft versions of these reports. For these reasons, the analysis here presents information from both the CEC and ICF Consulting reports, and describes what is known and not known about the differences. For our purposes here, “perfect” information and understanding of differences is not essential, and our analysis of various GHG-reduction policies is not particularly sensitive to modest variations in emissions inventories and projections.

Summary

Three of California’s methane-emitting sectors were examined: natural gas systems, landfills, and manure management. According to CEC(2005) estimates, these three sectors in 2000 comprised over half (17.7 $MMTCO_2$ eq.) of California’s total methane emissions (30.3 $MMTCO_2$ eq.). Most of the remaining methane emissions in California were from enteric fermentation (7.3 $MMTCO_2$ eq.) and wastewater treatment (1.8 $MMTCO_2$ eq.), sectors which were not examined as part of this analysis.

The quantity of emissions reductions that can technically be achieved varies by sector, due to the varying levels of overall emissions and the fraction that can potentially be captured. For the natural gas systems, about 36 percent of the emissions could be captured, while the landfill and manure management sectors were estimated to have 85 and 65 percent, respectively, of their emissions potentially subject to capture. For the three sectors combined, about 72 percent of the aggregate emissions were potentially subject to capture. With forecasted emissions in 2010 and 2020 of 21.5 and 23.2 $MMTCO_2$ eq., from these sectors, the total emissions reductions are estimated at 15.6 and 16.7 $MMTCO_2$ eq. for 2010 and 2020, respectively.

The cost of achieving these reductions varies over a broad range. About one-third of the potential reductions appear to be available for costs of less than $0, i.e., could be profitable under given tax and

[1] Such alternatives should also be considered for the landfill and natural gas sectors but were not evaluated as part of this analysis.

discount rate assumptions. About 85 percent of the potential reductions appear to be available at a cost of less than $10 per metric ton of CO_2 equivalent reduced. The tables in Attachment A show the specific actions, costs, and quantities available.

Four forms of trading systems were considered: (1) an allowance-based (or “cap-and-trade") system; (2) an opt-in allowance-based system; (3) a credit-based system; and (4) hybrid approaches that combined elements of the others. For each sector, six criteria were considered in evaluating the appropriateness of different trading approaches for the major methane emissions source categories: (1) ability to identify sources and entities; (2) measurability; (3) certainty of coverage; (4) potential for leakage; (5) administrative feasibility; and (6) transaction costs.

Including methane emissions as part of a broader GHG trading system is more complex than simply adjusting gas volumes by their respective global warming potentials (GWP). Most methane emission sources are fundamentally different from most CO_2 sources. Most CO_2 emissions can be viewed as *co-product emissions*, where the amounts of CO_2 are directly and immediately related to the activity’s inputs, particularly fossil fuel consumption. In contrast, most methane sources are *incidental emissions*, being either accidental releases or related to variable biological or geological processes. The resulting differences, particularly the differences in measurability (discussed below), have important implications for the feasibility of including these incidental emissions sources into a broader GHG trading system.

A key factor in determining the proper approach is *measurability*. Because methane emissions tend to be incidental to the activity causing the emissions, estimates of methane emissions are substantially more uncertain and difficult to measure than those for carbon dioxide. Contributing to the difficulty of measurement is that methane emissions often arise from many diffuse points, often small individually but collectively large. This uncertainty has implications for including methane in the trading system. When emissions from a source cannot easily be measured, it becomes more difficult to determine how many allowances that source should have in an allowance-based trading system.

Figure 1 summarizes our assessment for three of the major source categories of methane emissions in California. For some sectors, the intrinsic characteristics suggest that one particular trading approach is better suited than the others. For other sectors or subsectors, the choice is less clear-cut, and various approaches offer different combinations of advantages and disadvantages.

Approach

The purpose of this paper is to examine different approaches for including methane emissions in a GHG trading system. Because of this emphasis, the paper does not explore in depth alternative management approaches such as voluntary programs, command-and-control regulations, and financial mechanisms.

There is a key distinction between most methane emissions sources and most carbon dioxide emissions sources. For this analysis, it is helpful to distinguish between *co-product emissions* and *incidental emissions*:

FIGURE 1 SUMMARY OF ASSESSMENT FOR THREE METHANE SECTORS IN CALIFORNIA	
METHANE EMISSIONS SECTOR	BRIEF SUMMARY OF ASSESSMENT ON TRADING SYSTEM DESIGN
Natural Gas Systems	A credit-based system, probably expressed as a bounty for adoption of specific technologies and practices. Could be coupled with a hybrid allowance-based system where initial allowance requirements are based on volume throughput and activity factors. Alternatively, could be coupled with an increase in the carbon coefficient for natural gas consumption. In addition, with further improvements in leak detection, compressors may become suitable for an allowance-based system.
Landfills	A hybrid allowance and credit-based system. Allowance requirements for landfills would be estimated using indirect measures such as waste-in-place and regional climate factors, and credits would be given for site-specific measured reductions resulting from gas flaring or beneficial use.
Manure Management	A hybrid allowance and credit-based system for the large dairy operations. Allowance requirements would be estimated livestock population by type of animal coupled with average emissions factors. Credit-based component rewards measured reductions at liquid management systems. For swine operations and smaller dairy operations, there is much less potential for methane reductions, and these operations could reasonably be exempted or offered an opportunity to opt-in to a trading system.

- *Co-Product Emissions.* For CO_2, the emissions from fossil fuel combustion, cement production, and some other processes can be viewed as *co-product emissions*, where the amounts of CO_2 are directly and immediately related to the activity's inputs. For fossil fuel combustion, the carbon and oxygen in the fuel combine with oxygen to produce heat, H_2O, and CO_2. Similarly, in the cement industry, calcium carbonate is heated to produce calcium oxide (lime) in a process called calcination; carbon dioxide is a byproduct of the chemical reaction $CaCO_3 + \text{Heat} \rightarrow CaO + CO_2$. As a result, the total CO_2 emissions can be readily estimated from the quantity of input fuel consumed.
- *Incidental Emissions.* In contrast to CO_2, most sources of methane emissions are *incidental emissions*, being either accidental releases or related to variable biological or geological processes. The emissions are generally dispersed and the processes will often vary with site-specific conditions.

This comparative difficulty in identifying and measuring methane emission sources has important implications for integrating them into a GHG trading system. In general, where emissions are a co-product of a specific activity such as fossil fuel burning, measurements can typically be made with a high degree of precision. Incidental emissions, in contrast, are variably related to an activity's inputs, and are often spread out over time.

In exploring how methane sources could potentially be managed as part of a GHG trading system, this paper considers four primary sets of options:

- In an ***allowance-based (or "cap-and-trade") system***, each regulated source is a full participant in the trading program and must hold allowances to cover its total emissions. A source can purchase additional allowances in the market if its emissions exceed the allowances it holds. Conversely, entities that reduce emissions below their allowance levels can sell their excess allowances, generating revenue to offset the cost of implementing emissions reductions.

- In an ***opt-in allowance-based system***, certain methane sources could choose to voluntarily "opt in" to the trading program. In doing so, their emissions would be counted and covered by allowances. The coverage of the trading system would be expanded, and the trading system emissions cap would possibly be expanded to include these "new" sources. Presumably, a source would be willing to opt into a trading program if the rules enabled it to earn and sell excess allowances, or if by doing so it could avoid more onerous requirements.

- Methane sources could be allowed to earn credits for trade within the cap-and-trade system. Such a ***credit-based system*** may be appropriate for some source categories, particularly where measuring emissions *reductions* is more direct and more accurate than measuring overall emissions. Sources could be allowed to earn allowances (credits or offsets) by demonstrating emissions reductions. A credit-based program could be designed purely to help meet targets for capped sectors, or alternatively, could be a mechanism to get additional reductions from a specific sector (for example, a percentage of reductions could be required to be retired for the environment).

- Finally, trading systems could be developed that combined elements of an allowance-based program with a credit system. Such ***hybrid approaches*** might be considered where an entity's emissions are difficult to measure directly but can be reasonably inferred, and where specific actions to reduce emissions can be directly or indirectly quantified. An entity might initially be required to hold allowances on the basis of some industry-wide activity factors and then be awarded credits for specific emissions-reducing actions. The credit portion would reflect the entity's specific actions.

Six criteria were considered in evaluating the appropriateness of different trading approaches for the major methane emissions source categories. These were:

- ***Ability to Identify Sources/Entities***. For all types of emissions trading systems, it is necessary to be able to identify the sources that would be required to or allowed to participate in the program.

- ***Measurability.*** Measurement methods must be available at reasonable cost and must meet an acceptable standard of accuracy. Methods should also be verifiable to facilitate monitoring and enforcement. In an allowance-based and opt-in system, all participating sources will require emissions measurements. For a credit-based system, an ability to measure emissions *reductions* may be more useful than measuring emissions themselves.

- ***Coverage***. The more comprehensive the coverage of the trading system, the more environmentally effective and economically efficient the program is likely to be. An allowance-based system is more likely to examine a fuller set of cost-effective options, relative to opt-in and credit-based systems. Including all of a sector's entities creates more opportunities than excluding sub-sectors. However, this increased comprehensiveness must be weighed against increased transaction costs and administrative burdens.

- ***Potential for Leakage.*** Leakage is the loss of apparent GHG reductions through the shifting of emissions-producing activities to entities and facilities outside the trading system. Leakage is more likely to occur under a program that either covers a relatively small share of the total sources or sets a strong overall emissions cap. The less widespread the coverage provided by the trading system (i.e., the greater the availability of substitutes), the more likely leakage is to occur. If the additional burdens were modest, then this cost differential might not be sufficient to significantly shift emissions to unregulated sources. Conversely, if market prices for allowances were high relative to an entity's cost structure, then shifts and leakage could be greater.

- ***Administrative Feasibility***. For a trading system to be workable, the number of entities must be reasonably limited. Administrative feasibility also relates to the effort required for each entity in the program. Automated measurement and reporting methods can facilitate a relatively easy administrative load.

- ***Transaction Costs***. In any trading system there are apt to be economies of scale. If emissions at a single entity are small, then the transaction costs might be high on a per-ton basis. Transaction costs can also refer to the costs of entering into a trading system. In an allowance-based trading system, entry costs for an entity might be lower if standardized reporting and measurement is employed. With credit-based trading, the entry costs for an entity could be more substantial.

For this analysis, the six criteria were not quantified or assigned weights for use as part of a strict numerical evaluation. Indeed, the weights that one might assign to the criteria would likely differ from person to person, reflecting individual preferences and concerns. However, it was the case here that the criteria for *identification* and *measurability* figured prominently in the discussion and evaluation of suitable trading approaches.

Natural Gas Systems

The natural gas system in the U.S. is vast, being comprised of hundreds of thousands of wells, hundreds of gas processing facilities, over one million miles of pipeline, and millions of consumers. Methane emissions from natural gas systems are generally process-related, mostly stemming from normal operations, routine maintenance, and system upsets. On a per-component basis, emissions are small. Unlike other methane-emitting sectors, where methane emissions tend to be incidental emissions related to processes, methane emissions from gas and oil systems represent a loss of primary salable product.

Estimates of Methane Emissions from Natural Gas Systems

Figure 2 presents historical estimates of methane emissions from natural gas systems in California, as developed by CEC(2005). To develop these estimates, the CEC used California Air Resources Board (CARB) data that estimated methane emissions from area sources, including emissions from the petroleum and natural gas supply system. Methane emissions were estimated by CARB from total organic gas (TOG) emissions using a speciation profile to determine the fraction of TOG comprised of methane. CARB provided data in tons/day; these were converted into metric tons per year. Note that in CEC's inventory, some natural gas methane emissions are embedded in the totals for petroleum and natural gas, since many of California's operations co-produce gas and oil.

ICF's estimates for historic and forecast emissions were developed for California using the Almanac Projection Data System maintained by CARB.[2] This database is a compilation of emission estimates

[2] 2005 Almanac Projection Data. California Air Resources Board. Available online at http://www.arb.ca.gov/ei/emsmain/reportform.htm.

Figure 2 Natural Gas System Methane Emission Estimates for California ($MMTCO_2$ eq.)		
Year	CEC(2005) Estimate	ICF Consulting Estimate
1990	3.3	--
1995	2.7	--
1999	2.0	--
2000	1.9	1.81
2002	1.9	--
2005	--	1.89
2010	--	2.00
2015	--	1.89
2020	--	2.19

reported by California's 35 local air districts. The database reports emissions of total organic gases (TOG). To derive the methane portion of these total organic gases, ICF used 15 CH_4 speciation factors for the oil and natural gas industries, provided by CARB and correlating with different aspects of the extraction, production, and refining processes. ICF assigned these factors to individual emission source categories based on professional judgment. This appears to be consistent with CEC(2005) in the underlying data and assumptions.

Potential for GHG Reductions from Natural Gas Systems

There are a number of technologies and practices that ICF analyzed for mitigating methane emissions from natural gas systems. The percent of emissions to which each option is applicable, based on economic conditions (i.e., market penetration), reduction efficiency, and cost data associated with each option are based on the U.S. EPA report entitled *International Analysis of Methane and Nitrous Oxide Abatement Opportunities: Report to Energy Modeling Forum, Working Group 21.* Reduction efficiencies and cost data included in the report are themselves based on company-specific information collected by the U.S. EPA's Natural Gas STAR Program, and presented in numerous "lessons learned" studies and partner-reported opportunities.

Tables 1 and 2 in Attachment A show the results of ICF's analysis of natural gas systems methane reduction potential, for both 2010 and 2020. The scenarios shown here assume a discount rate of 4 percent, and a tax rate of 0%. ICF's analysis indicates modest GHG reduction potential – in total about one-third of the total sector emissions. Of these potential reductions, about two-thirds (i.e., about one-fourth of the total sector emissions) appear to be available at a net cost benefit. Most of the remaining reductions are achievable at a much higher price, usually over \$10/metric ton CO_2 equivalent.

Considerations and Recommendations for Natural Gas Systems

At the national level, emissions estimates are based on joint research conducted primarily in 1992 and updated by the Gas Research Institute and EPA. The original study used statistical sampling techniques, applied at "model" facilities, to derive emissions factors for about 100 emissions categories in the natural gas system. These emissions factors are combined with activity factors to derive total emissions. But while the activity factors are adjusted annually based on production data surveys, the emissions factors have generally remained constant.

The measurement approach undertaken for the national level inventory does not easily lend itself to the measurement of emissions reductions at the facility level, because the emissions factors derived from current sampling at a small number of "model facilities" cannot be used to make an accurate estimate of emissions or reductions at a particular facility. This is for two reasons: First, actual emissions vary widely from site to site depending on equipment, maintenance, operating procedures, and other factors, so national emissions factors do not accurately predict emissions from individual facilities. Additionally, current measurement methods designed to measure concentrations near a leak may show a poor correlation between concentrations and emissions. Also, the use of historic emissions factors will not measure the effect of efforts to reduce emissions.

The extensive scope of the natural gas system in the U.S. poses a substantial challenge for administering any broad-based system of achieving methane reductions. On a per-component basis, emissions are small. For example, EPA's national estimate of 33.2 MMT CO_2 equivalent to have been emitted from natural gas distribution systems in 2002 spans a network of 1.5 million miles of distribution pipeline and over 40 million customer meters. The leaks across this vast network are typically small but numerous, irregularly distributed, and difficult to specifically track and measure. Accordingly, the administrative cost-effectiveness of broad-based coverage is apt to be low.

Because of these measurement difficulties and the vast scope of the gas system, it will in general be difficult to include methane emissions from the natural gas system in an allowance-based program. Instead, a credit-based approach to trading seems generally more appropriate in this sector. Given the aforementioned difficulties in site-specific measurement, a "bounty schedule" (expressed as a number of credits per volume of gas) for adoption of specific technologies and practices might be a more workable approach than documenting actual emissions reductions. This credit-based approach could be used either in addition to or in place of non-trading mechanisms (e.g., requiring the adoption of specific technologies and practices).

However, the use of a credit-based approach alone would result in a lack of coverage of emissions sources. A hybrid approach could combine this credit or bounty approach with elements of an allowance-based cap-and-trade system. An estimate of allowances needed for a facility would be estimated using indirect methods and activity factors in conjunction with volumes of gas at a facility or distribution stage. Then, where emissions reduction activities were undertaken, credits could be awarded either for measured emissions reductions or as a bounty. The difference between the credits earned and allowances needed would represent the number of allowances stilled needed (if credits were less) or available for trading (if credits were more).

Another way to ensure that the natural gas sector (and its users) bear the cost of fugitive emissions may be to increase the emissions factor used to calculate CO_2 emissions from the combustion of natural gas. If the natural gas carbon coefficient were increased from 117 lbs. CO_2/MMBtu to about 125 or 126 lbs. CO_2/MMBtu (for an assumed one percent loss rate), then in a downstream system the allowance requirement imposed on natural gas consumers would cover both carbon dioxide emissions from the combustion of natural gas and fugitive methane emissions. This approach could be combined with a credit-based approach so that the trading system provided both broad coverage and proper incentives to make reductions.

It may be also possible to include some subsectors of the gas system directly into an allowance-based trading program. In particular, compressor stations, which are significant sources, relatively small in number, and relatively easy to measure, could more easily be brought into an emissions trading program. Before this could happen, however, further improvements may be needed in the accuracy and efficiency of leak detection; recent developments in technology appear to be making progress toward this end.

Landfills

Although both municipal solid waste (MSW) and industrial landfills produce methane, MSW landfills proportionately produce more methane. Emissions from MSW landfills, which received about 61 percent of the total solid waste generated in the United States in 2002, accounted for about 94 percent of total landfill emissions, while industrial landfills accounted for the remainder. Methane production varies greatly from landfill to landfill depending on site-specific characteristics such as the quantity of waste in place, waste composition, moisture content, landfill design and operating practices, and climate. Unless captured first by a gas recovery system, methane generated by the landfill is emitted to the atmosphere when it migrates through the landfill cover.

Estimates of Methane Emissions from Landfills

Landfills are the largest anthropogenic source of methane emissions in the United States. According to EPA, U.S. landfill methane emissions in 2002 were approximately 193 million metric tons CO_2 equivalent (9,192 Gg). From 1990 to 2002, net methane emissions from landfills decreased by approximately 8 percent. This slightly downward trend in overall emissions is the result of increases in the amount of landfill gas collected and combusted by landfill operators, which has more than offset the additional methane emissions resulting from an increase in the amount of municipal solid waste landfilled.

Forecasts of U.S. landfill methane emissions are generally based on two key factors: (1) projections of waste generated; and (2) the percentage of the waste stream that is landfilled each year (as opposed to recycling and/or combustion). Significant reductions in future emissions are expected; EPA's baseline forecast for total U.S. emissions shows emissions from landfills declining to 174.5 $MMTCO_2$ equivalent by the year 2020.

As estimated in CEC(2005), California landfill methane emissions remained at roughly 10 $MMTCO_2$ eq. over the 1990-2000 period. These are seen as part of Figure 3. The CEC(2005) estimates were developed from emissions data obtained from local air pollution control agencies via the CARB. It is more of a "bottoms up" approach based upon a facility-by-facility assessment conducted by the local air districts, rather than a top-down approach developed from estimates of total waste and disposition.

The CEC(2005) estimates are less than their estimates presented in CEC(2002). In that earlier document (p. 32, 35-36), methane emissions were estimated at about 17 $MMTCO_2$ eq. in 1990, declining to about 13 $MMTCO_2$ eq. in 1999. In developing these earlier estimates, the total amount of waste-in-place in California landfills increased from 760 million tons in 1990 to 932 million tons in 1999, resulting in CH_4 generation increasing from 27.1 $MMTCO_2$ eq. in 1990 to 31.8 $MMTCO_2$ eq. in 1999. This was more than offset by the amount of CH_4 recovered, meanwhile, which increased from 7.6 $MMTCO_2$ eq. to 15.7 $MMTCO_2$ eq. during this period. The net effect of these two trends – the relatively modest increase in CH_4 generation coupled with the large increase in recovery – was a 22 percent decrease in net landfill emissions over the ten-year period.

The CEC(2005) report notes the lowering of historic emission estimates that came about with the change in estimation methodology. It states that "Values look low compared to 1990-1999 inventory," and that "Landfill methane emissions should be reviewed in more detail" in order that these discrepancies can be resolved.

Figure 3 Landfill Methane Emission Estimates in California ($MMTCO_2$ eq.)		
Year	CEC(2005) Estimate	ICF Consulting Estimate
1990	10.0	--
1995	9.8	--
1999	9.9	--
2000	9.9	9.87
2002	10.1	--
2005	--	10.25
2010	--	10.64
2015	--	11.07
2020	--	11.43

In ICF(2005), baseline emissions forecasts for California landfills were based on data provided by CARB, with references to CARB's 2005 Almanac Projection Data, available online at www.arb.ca.gov/ei/emsmain/reportform.htm. ICF used CARB published estimates of historical and projected emissions of total organic gases (TOG), assumed certain anticipated future control measures, and adjusted TOG values to include CH_4 only (estimated at 98.6% of TOG). The resulting forecast, also shown in Figure 3, shows a very slight growth in emissions, about 1 percent per year through 2020.

Even more than the CEC(2005) estimates of historic landfill emissions changed when they changed their estimation methodology, ICF's baseline projections showed substantial changes from their earlier draft, which were more than triple the levels seen in their June 2005 report. These changes are discussed here not so much to find fault with earlier drafts, but instead to highlight the uncertainty in these figures and the need for caution in using them.

In their March 2005 draft report, ICF calculated baseline emissions for California landfills over the 2000-2020 period. Their methodology used available data on individual landfills in California obtained from CEC, and added in landfill data from EPA's Landfill Methane Outreach Program (LMOP) database on landfill gas to energy (LFGTE) projects. By assuming future rates of waste disposal, biogas production was estimated. Adjustments were then made for EPA's Landfill Rule,[3] both for those already subject to the rule and those whose disposal rate would make them subject to the rule in coming years.

[3] For larger landfills, emissions of landfill gas (comprised mainly of methane, carbon dioxide, and nonmethane organic compounds (NMOCs)) are regulated under the Clean Air Act as a result of the landfill New Source Performance Standards (NSPS) and Emissions Guidelines (EG), promulgated by the U.S. Environmental Protection Agency (EPA) on March 12, 1996. Under this "Landfill Rule," gas collection and control systems are required for any landfill that (1) does or did accept municipal solid waste, (2) was active on or after November 8,

The baseline forecasts developed in ICF's analysis resulted in estimated California landfill emissions in 2000 of 30.90 MMTCO_2 eq., rising to 44.74 MMTCO_2 eq. in 2020. These quantities were three to four times the emissions they now show in their June 2005 report. ICF's revised forecast also reflects a methodological change, and the documentation does not discuss the previous methodology or attempt to reconcile the two different projections.

There was an apparent problem regarding one of ICF's assumptions in their March 2005 draft report, and this may have affected their calculations of methane emissions and/or the cost of mitigation. On page 39 of that report, they indicate that they have assumed a waste density of 1.667 tons per yard in the landfills. For comparison, this is about twice the density of water. For landfills, compacted MSW is usually assumed to have a density of about 0.50 to 0.75 tons per cubic yard. If it was the case that ICF's stated assumption of 1.667 tons per cubic yard was not a typo, then it might have also affected the methane emission estimates (by inflating the calculated tons in place of MSW), and most likely would have also affected the cost estimates for methane recovery.

This issue was raised in discussions with ICF Consulting. They later indicated that the value of 1.667 tons per cubic yard was a typo, and that the reciprocal value of 1.667 cubic yards per ton was actually intended. Applied to waste-in-place estimates, this lower factor would reduce the estimated tons by nearly two-thirds, and would have made their draft forecasts of emissions more in line with the CEC estimates. However, in saying that the error was only a typo in documentation and not an error in the methodology, we are not presented any plausible reasons for the dramatic downward revision in forecast emissions. The distinction is more than one of simple nit-picking. If an incorrect density factor was used in ICF's cost methodology, then their costing model would show much more methane generated per acre, and hence a much lower cost per ton of collecting methane. Until a more definitive understanding can be gained of the changes from ICF's earlier draft, it is appropriate to view the estimates of the cost of landfill methane reduction with caution.

Potential for GHG Reductions from Landfills

Landfills can install direct gas use projects or electricity projects with backup flare systems to recover and use methane. Because the costs and GHG savings of each project type (i.e., direct gas use or electricity) are dependent in part on the landfill size, ICF grouped the landfill population into seven size categories. The technical applicability of each mitigation option is dependent on the amount of landfill gas generated by landfills in a given size category. Project costs are driven by two main factors – landfill size and landfill age. In general, larger landfills tend to have more cost-effective projects. The larger the landfill, the greater the amount of methane produced, and the greater the amount of direct gas or electricity the landfill can sell. Age impacts methane generation since it dictates the stage of decomposition of the waste in place (WIP) and rate of landfill gas generation.

Tables 3 and 4 in Attachment A show the results of ICF's analysis of landfill methane reduction potential, for both 2010 and 2020. The scenarios shown here assume a discount rate of 4 percent, and a tax rate of 0%. ICF's analysis indicates substantial GHG reduction potential – over three-fourths of total landfill methane emissions. The largest potential reductions come from those landfills with over one million tons WIP (and presumably not yet subject to the Landfill Rule limits), either by installing equipment for electricity generation or for direct gas use. Further, the cost of these reductions is less than $1 per ton CO_2 equivalent (for electricity), or profitable (for direct gas use).

As described above, there are still unresolved questions regarding the possible misuse of a density factor and its effect on the costs of reductions. The resolution of these issues could have a substantial effect on the relative economic attractiveness of emissions reductions from this sector.

1987, (3) has a total permitted capacity of at least 2.5 million metric tons of waste, and (4) has NMOC emissions of at least 50 metric tons per year.

Considerations and Recommendations for Landfills

For larger landfills – particularly those subject to the Landfill Rule – the number of landfills and approximate amount of waste in place are known with reasonable certainty. However, for the remainder of the landfill population there is uncertainty as to both population and total waste in place. As part of EPA's voluntary Landfill Methane Outreach Program, EPA has been involved in an on-going effort to gather information on MSW landfills, and to develop state-specific landfill profiles. The information has been assembled from state and local sources, various national solid waste publications, landfill owners and operators, and project developers. While the data is often thorough, it is nonetheless gathered as part of a voluntary program, and as such includes some data gaps, missing data elements for some landfills and other landfills entirely.

At an individual landfill, there is substantial uncertainty in estimating methane emissions. Total waste in place may be uncertain, particularly for older landfills. Factors affecting the rates of decomposition and the timing and amount of methane generation are very site-specific, and data may not be adequate.

Even at sites where landfill methane is collected, there are still residual emissions. It has been estimated that about 75 percent of the gas is captured in the collection system, and perhaps up to 10 percent of the rest is oxidized on its way through the cap. The remaining gas is still emitted as methane from the landfill site, but there is currently very little data measuring this.

Because of these measurement difficulties, landfills could not be easily included in an allowance-based cap-and-trade system. Similarly, measurement difficulties, both for baseline and future emissions, make an opt-in approach not well suited for this sector.

However, where gas capture systems are in place, measurement of emissions *reductions* resulting from methane capture and/or flaring technologies can be readily measured. As a result, a credit-based system could be workable. However, for some landfills already collecting methane the question of additionality comes into play. Also, because a credit-based system is voluntary, it may only capture a portion of the sector, so there could be a net increase in emissions from the sector as a whole even if some sources make reductions.

A policy approach that could rectify these problems would be a hybrid allowance and credit-based system. Initial allowance requirements would be based upon gross emissions using indirect measures, and adjusted for methane captured pursuant to the Landfill Rule or other requirements. Smaller landfills not subject to the Landfill Rule or other requirements would simply have their initial allowance requirements based upon gross emissions using indirect measures. For smaller landfills, credits could be earned for gas collection and flaring, and additional credits if beneficial use is made of the gas. For sources that are already reducing emissions under the Landfill Rule, credits would be largely restricted to beneficial use of the gas, which does not further reduce methane emissions but instead displaces CO_2 emitted from other energy use.

Manure Management

Liquid manure management systems, such as lagoons, ponds, tanks, or pits, tend to produce significant quantities of methane. The general trend in manure management – in part because of the trend towards larger automated farms – is toward increased use of the liquid systems that produce greater quantities of methane emissions.

Dairy and swine operations are the primary types of livestock operations where liquid and slurry manure systems are used, and account for over 80 percent of total emissions from this source category. Emissions are relatively concentrated at the larger farms, with less than one-tenth of the farms accounting for about half the emissions.

Estimates of Methane Emissions from Manure Management

Most manure is currently handled as a solid (e.g., in pastures or stacks on dry lots); however, this management as a solid produces only a small percent of total methane emissions from manure. Liquid manure management systems handle a much smaller portion of total manure but comprise most of the total methane emissions from manure. As a consequence of this industry trend toward liquid management systems, combined with changes in animal populations and feed consumption, methane emissions from manure management have been rising steadily over the past few years and are projected to continue rising.

Methane emissions from manure management are not measured directly, but are estimated (and projected) from models. EPA's inventory model calculates methane emissions for each animal group as a function of the animal population, volatile solids produced per animal, methane-producing potential of the volatile solids, and state and animal-group-specific factors.

In 1990, livestock manure emitted about 31.0 $MMTCO_2$ (1.48 MMT CH_4) of methane in the United States. Over the last eight years, methane emissions from manure have generally followed an upward trend, as a consequence of greater use of liquid manure management systems. EPA estimates that U.S. emissions from this source had risen to 39.5 $MMTCO_2$ (1.88 MMT CH_4) in 2002. About 45 percent of the emissions are attributable to swine operations, another 39 percent are attributable to dairy cattle, and the remainder attributable to poultry, beef cattle, and other breeds of livestock.

EPA projects further increases in livestock population growth, driven by increases in total meat and dairy product consumption and in increasing use of liquid waste systems. Because of this, emissions from livestock manure in the U.S. baseline are projected to increase. EPA's Baseline emissions forecasts indicate methane emissions reaching 38.5 $MMTCO_2$ (1.83 MMT CH_4) in 2010, and increasing to 42.9 $MMTCO_2$ (2.04 MMT CH_4) by 2020.

Figure 4 presents historical estimates of manure emissions from methane management in California, as developed in CEC(2005). From a 1990 emissions level of 3.6 $MMTCO_2$ eq., methane emissions increased to 6.3 $MMTCO_2$ eq. in 2002. These estimates are modestly higher than those developed in CEC(2002). Also as developed in CEC(2002), about 90 percent or more of these emissions were from dairy cattle, with the remainder comprised mostly from beef cattle, swine, poultry, and horses.

ICF calculated California's methane emissions from manure management systems using the EPA methodology based on animal population in each manure management system and average animal characteristics such as animal waste and volatile solids produced. This analysis relied on state averages for animal characteristics and distribution of manure management system types. ICF obtained historical animal populations from the California Department of Food and Agriculture (CDFA). Animal population growths were based on national projections. Adjustments were made to account for those farm operations already operating digester systems.

Also shown in Figure 4 are ICF's estimates for manure management methane emissions in California. For 2000, ICF's emissions estimate is higher than the CEC(2005) estimate. Most of this difference is probably due to ICF's inclusion of N_2O emissions from manure management systems (but not N_2O emissions from manure used for fertilizer applications). ICF estimates these N_2O emissions at 25 percent of total GHGs from manure, implying that its estimate of 2000 methane emissions alone would be very nearly the same as the CEC(2005) estimates.

California's livestock populations vary from the national averages, both in terms of population and distribution by size of operation. The animal populations, by type of animal, are a primary determinant of methane emissions. However, the size of the operation is an important indicator of the economic feasibility of regulating. On average, annual manure management emissions from dairy cattle are less than two metric ton of CO_2 equivalent per head, while emissions from hogs and pigs are only about 0.3 metric ton of CO_2 equivalent per head. For the smaller-sized operations, the diseconomies of small scale can pose a large cost for relatively little environmental benefit.

FIGURE 4 MANURE MANAGEMENT METHANE EMISSION ESTIMATES IN CALIFORNIA ($MMTCO_2$ eq.)		
Year	CEC(2005) Estimate	ICF Consulting Estimate
1990	3.6	--
1995	5.0	--
1999	5.9	--
2000	5.9	7.82
2002	6.3	--
2005	--	8.50
2010	--	8.85
2015	--	9.20
2020	--	9.54
Note: ICF's estimates include N_2O emissions from manure management systems (but not N_2O emissions from manure used for fertilizer applications). ICF estimates these N_2O emissions at 25% of total GHGs from manure.		

For milk cows, California has a proportionately large share of the U.S. inventory. While California as a state has about 12.3 percent of the country's people in 2001, it had about 17.4 percent of the milk cow population, about 1.59 million milk cows.[4] Additionally, the size distribution of California's operations is heavily skewed toward larger operations. California in 2004 had only 2,300 (2.8%) of the U.S.'s 81,440 operations; whereas fewer than 4 percent of the U.S. operations are larger than 500 head, nearly half of California's are. Additionally, 98 percent of California's Milk Cows are housed in operations that are over 200 head, compared to a national average of only 58 percent.[5]

For hogs and pigs, California has a very small share of the U.S. total. In 2002, the 150,000 hogs and pigs represented a mere 0.25 percent of the Nation's population.[6] With 750 operations in the state, the

---

4 U.S. Department of Agriculture, National Agricultural Statistics Service, *Agricultural Statistics 2004,* Chapter VIII, "Dairy and Poultry Statistics," Table 8-11, "Milk and Milkfat Production: Number of milk cows, production per cow, and total quantity produced, by States, 2001," http://www.usda.gov/nass/pubs/agr04/acro04.htm.

5 U.S. Department of Agriculture, National Agricultural Statistics Service, *Farms, Land in Farms, and Livestock Operations 2004 Summary*, Publication # Sp Sy 4 (05), January 2005, pages 22-27 (Milk Cows). http://usda.mannlib.cornell.edu/reports/nassr/other/zfl-bb/

6 U.S. Department of Agriculture, National Agricultural Statistics Service, *Agricultural Statistics 2004,* Chapter VII, "Statistics of Cattle, Hogs, and Sheep," Table 7-26, "Hogs and Pigs: Number and Value, by States, 2002-

average operation had 200 head, much smaller than the national average. With average per-head emissions from hogs and pigs of only about 0.3 metric ton of CO_2 equivalent, California's average size operation would emit fewer than 100 metric tons CO_2 equivalent.

Using California's percentages of U.S. totals, it is difficult to reconcile ICF and CEC estimates with EPA's national estimates. As seen in Figure 5, EPA estimated that in 2002, out of a total of 39.5 $MMTCO_2$ eq. methane emissions from manure management, 15.4 came from dairy cattle and 17.7 from swine. Based only upon California's share of the livestock population, one would expect manure management emissions to be only a few percent of the national total, roughly 2.7 $MMTCO_2$ eq., nearly all of that from dairy cattle. However, both CEC and ICF estimate California's emissions to be about twice this amount (recognizing that ICF's estimates in Figure 4 also include N_2O emissions from manure management systems). The reason for this difference is not yet known; one possible explanation may be if California has a higher proportion of liquid manure management systems than the national average.

Potential for GHG Reductions from Manure Management

FIGURE 5
NATIONAL METHANE AND N_2O EMISSIONS FROM MANURE MANAGEMENT
(million metric tons CO_2 eq.

Gas/Animal Type	1990	1996	1997	1998	1999	2000	2001	2002
CH_4	**31.0**	**34.6**	**36.3**	**38.8**	**38.6**	**38.0**	**38.8**	**39.5**
Dairy Cattle	11.4	12.8	13.4	13.9	14.7	14.6	15.1	15.4
Beef Cattle	3.1	3.2	3.1	3.1	3.1	3.0	3.0	3.0
Swine	13.1	15.3	16.4	18.4	17.6	17.1	17.4	17.7
Sheep	0.1	+	+	+	+	+	+	+
Goats	+	+	+	+	+	+	+	+
Poultry	2.7	2.6	2.7	2.7	2.6	2.6	2.7	2.6
Horses	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
N_2O	**16.2**	**17.0**	**17.3**	**17.3**	**17.4**	**17.7**	**18.0**	**17.8**
Dairy Cattle	4.3	4.0	4.0	3.9	4.0	4.0	3.9	3.9
Beef Cattle	4.9	5.1	5.4	5.5	5.5	5.9	6.1	5.9
Swine	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Sheep	+	+	+	+	+	+	+	+
Goats	+	+	+	+	+	+	+	+
Poultry	6.3	7.2	7.2	7.2	7.2	7.2	7.3	7.4
Horses	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Total	**47.2**	**51.6**	**53.6**	**56.1**	**56.0**	**55.7**	**56.8**	**57.3**

\+ Does not exceed 0.05 Tg CO_2 Eq.
Note: Totals may not sum due to independent rounding.

Source: U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2002,* April 15, 2004, Table 6-6, page 6-7, http://yosemite.epa.gov/oar/globalwarming.nsf/content/ResourceCenterPublicationsGHGEmissionsUSEmissionsInventory2004.html.

While methane is produced by all types of manure management systems, systems that store manure generate methane at a much greater rate than other systems (e.g., an open pasture). However, these manure management systems can be adjusted to help capture and reduce the methane emitted to the atmosphere. Anaerobic digester systems put the manure into specially designed containers sealed from the atmosphere

2003," http://www.usda.gov/nass/pubs/agr04/acro04.htm.

that capture the methane and either combust it through a flare, or utilize the methane for electricity generation.

The installation of lagoon covers or plug flow digesters reduces methane emissions from manure management systems by capturing emissions and utilizing them to produce heat or electricity. Although this analysis includes several other types of management systems in the baseline, in general, only emissions from liquid slurry systems and anaerobic lagoons can be mitigated. Consequently, only emissions from swine and cattle are included in ICF's mitigation analysis.

Tables 5 and 6 in Attachment A show the results of ICF's analysis of manure management methane reduction potential, for both 2010 and 2020. The scenarios shown here assume a discount rate of 4 percent, and a tax rate of 0%. ICF's analysis indicates GHG reduction potential of about two-thirds of total manure management methane emissions – coming from dairies of various sizes. As expected, the economics favor GHG reductions at the larger dairies, where the economies of scale are most favorable. As noted above, California's dairies are heavily concentrated in the larger size ranges. Because of this, about one-third of the baseline emissions (and about one-half of the total estimated reduction potential of 2.78 $MMTCO_2$ eq. in 2010 and 2.99 $MMTCO_2$ eq. in 2020) could be achieved at a net cost benefit. At a $10 per ton CO_2 equivalent cost, 57 percent of the baseline emissions could be reduced. Importantly, however, these ICF results may underestimate the actual cost of GHG mitigation from this sector because they do not appear to consider the costs of NO_x control in nonattainment areas. NO_x control requirements for biodigesters are currently under consideration.[7] Additional analysis is needed to evaluate the costs of adding NO_x controls to biodigesters for different sized units and under different net metering assumptions.[8]

Considerations and Recommendations for Manure Management

The methane that is actually produced from a given quantity of animal waste is difficult to estimate. While the maximum amount of methane that an animal's waste can produce can be measured fairly accurately in the laboratory, the share of that maximum attained in actual waste management regimes is much more uncertain. Changes in temperatures and the feed characteristics affect the potential methane production of the resulting manure. The types of waste management systems and the ambient air temperatures vary across and within states, and this leads to different states having widely different factors.

More accurate techniques are available for estimating emissions from liquid management for farms that recover methane. As part of the recovery process, farms can obtain relatively accurate measurements of the gas recovered from the portions of the lagoon that are covered, and the methane content of the gas, which does not vary significantly over time. Residual emissions could also be estimated for the portions of the lagoon that are uncovered. Although the estimate would not be straightforward, EPA's AgSTAR software could be modified to assist farmers in this calculation.

Switching from liquid to dry management systems is largely impractical for both environmental impact and process design reasons. With the use of liquid-based systems, the primary method for reducing emissions is to recover the methane through the use of covered anaerobic digesters (at farms that have engineered ponds for holding liquid waste) and complete-mix and plug-flow digesters (for other farms). This recovered methane can be flared or used to produce heat or electricity.

---

[7] NO_x emissions from digester generators can be reduced through use of lean-burn engines or installation of select catalytic reduction (SCR) technology. American lean-burn engine models are not currently available below 350 kW, so this would be an option for large dairies only. The use of SCR with digesters is largely untested and requires prior cleanup of the waste gas, which increases the complexity and required maintenance of the engine. The cost of NO_x control could be prohibitively expensive for many digester projects should such reductions be required.

[8] We had hoped that CEC and ICF Consulting would undertake this analysis before finalizing their report. However, this work did not fit their time and budget constraints.

A range of potential approaches for regulating methane emissions from manure management systems are available. They range from strictly voluntary approaches and incentive programs that would encourage, but would not require, farmers to take action to reduce emissions through installation of methane digesters, to command-and-control regulations and emissions trading programs that would impose mandatory technology, emission rate or total emissions requirements on the dairy industry. The general frameworks for manure methane regulation include:

- *Voluntary Programs*. Under a voluntary framework, dairy farms would be encouraged but not required to install digester systems. The structure of such a program would likely be similar in form to existing voluntary programs such as the US Environmental Protection Agency's AgSTAR program, which provides information and training to dairy and other farms across the country that seek to install digester technology. The advantage of such an approach is that it would be the most feasible from a political standpoint, and would likely meet minimal opposition from dairy farmers. It appears unlikely to have much impact in the current climate, however. The main benefit to the farm from digester installation is that it allows the farmer to offset some or all of its electricity demand through on-site power generation and net metering (although methane may also be consumed directly on some farms). The three major investor-owned utilities in California have been opposed to allowing distributed generators to link to the grid, however. The interconnection process can be time-consuming and prohibitively expensive for dairy farms.[9] The current net metering law (Assembly Bill 2228) that established a pilot program to guarantee net metering to eligible digester projects is also very limited; it requires the utilities to offer net metering only up to an aggregate total of 15 MW, does not allow farmers to sell excess electricity above their demand back to the utility, and is due to expire in January 2006. In such an environment, digester installation would thus appear to be an investment of dubious value to many farms.

  Another factor inhibiting voluntary action by dairy farms is that electricity generation has generally been incidental to their work. Unlike some industries where on-site electric power production is often an integral part of the process (e.g., pulp and paper, oil refining, iron and steel), dairies typically purchase their power from the grid. With the primary focus of dairy farmers on milk production, farmers may also be unfamiliar with digester generation technologies and programs and their potential benefits, and they may be less willing to bear the risk from such investments as a result. Farmers are therefore likely to be unwilling to take the risk of installing digester projects even in the (highly uncertain) event that long-term net metering could be guaranteed. A purely voluntary program therefore appears unlikely to produce many new projects, and the emission reductions achieved would most likely be minimal.

- *Incentive Programs.* Incentive-based approaches would provide financial assistance to qualified digester projects. Incentive payments for methane regulation could be offered in a variety of forms, such as a share of the total project capital cost, a share of the digester or generator cost only, or a production tax credit based on total generation or methane consumed or flared. An example of such a program is the 2001 Dairy Power Production Program (DPPP). The DPPP provides financial assistance for digester development to eligible dairy farms through buydown grants covering up to 50% of the total capital costs of the system and electricity generation incentive payments. A voluntary program would lower the cost of digester projects and encourage new development. The record of the DPPP indicates that the overall participation level and the total reductions achieved may still be relatively small, however. Despite its generous incentive structure, only about 60

[9] Note that wind and solar unit projects face a less expensive, more direct interconnection procedure.

out of more than 2,000 dairy farms statewide applied for the program (14 proposed projects with a total capacity of about 3.5 MW had been approved for grants as of May 2004). Achieving higher levels of reductions would likely require a more aggressive program with much higher funding levels and/or guaranteed net metering. These changes may be politically difficult to achieve.

- *Technology Requirements and Emissions Benchmarks*. A stronger, more robust approach to regulation of methane from manure management would mandate the installation of specific digester technologies on dairy farms, or would require farms to meet a specific CO_2-equivalent emission rate per animal or per unit of economic output. With a technology requirement, ideally policy makers would attempt to match the characteristics of farms in certain categories (e.g., size, type of manure handling systems used, interconnection potential, etc.) with the most appropriate digester and end-use (electricity generation, direct consumption, or methane flaring) technology. In contrast to voluntary or incentive programs, a technology requirement would ensure broad participation, and would therefore obtain significant emission reductions below business-as-usual levels. In addition, since the required technologies would be specified, the program could also be designed to ensure that new digester electricity generation projects conform to specific nitrogen oxide (NO_x) emission limits, an issue of growing concern in nonattainment areas.[10]

  The main disadvantage of this approach is that the costs to many of the participating dairies would be very high, particularly since some dairies would find installation of digester projects to be prohibitive even using the most cost-effective technology available. This program would thus be expected to meet significant opposition. To be economically successful and feasible, at a minimum a technology program would have to be coupled with an extension and expansion of the current net metering law. Allowing dairies to sell excess electricity back to the grid would also help to lower the cost borne by the farmer. Another option would be to have the state bear part of the costs by coupling the technology requirement with an incentive program. The state could also allow flaring in some cases; such an option would not require installation of an electric generating unit, and could lower the total cost while still achieving significant reductions in methane emissions.

  In the case of a benchmark approach, farms would be required to meet a given emissions rate, which is referenced to various technology options and/or best practices at similar farms. Benchmarking may provide more compliance flexibility than a technology-based approach in terms of how the standard is set and the potential set of compliance options. However, absent net metering or other incentive programs and depending on the level of the benchmark, this approach would also be expected to increase costs for dairy farmers.

  It should be noted that although both of these approaches would reduce emissions below their expected business-as-usual levels, no limits would be imposed on the total emissions from dairy farms. A program based on technology requirements or emissions benchmarks would therefore risk an increase in total methane emissions should dairy farm production increase over time.

- *Allowance-Based (Cap-and-Trade) Programs*. In an allowance-based, or “cap-and-trade,” system, an overall emissions limit equal to a given number of allowances is set for the sector, and each regulated source must hold sufficient allowances to cover its total

[10] For example, Rule 4702 of the San Joaquin Unified Air Pollution Control District would require digester engines to meet a limit of 90 ppmv NOx by 2008. This represents a significant reduction from the uncontrolled emission level of 200 to 300 ppm.

emissions. A source can purchase additional allowances if its emissions exceed the allowances it holds, while entities that reduce emissions below their allowance levels can sell their excess allowances, generating revenue to offset the cost of implementing emissions reductions. By setting a cap on total methane emissions from dairy farms, a cap-and-trade program would prevent emissions from increasing due to growth in total farm sector output. In contrast to the other programs considered here, such a program would therefore guarantee the achievement of a given emissions level. By allowing farms with high operating costs to comply by purchasing emission permits, it would also help to lower the total costs of compliance below those in a technology-based approach. Emissions trading would also allow for the possibility of linking dairy regulation with other sectors (e.g., electric power, industry), which could lower compliance costs even further. As with the other approaches, to be effective this program would almost certainly require net metering. The main disadvantage of a cap-and-trade program would be the inevitable opposition from dairy farms subject to potential regulation. Allowing additional compliance options (i.e. flaring of methane on-site or purchases of emission offsets from off-site sources) could help to lower costs and reduce opposition.

In addition to the above measures, policies to overcome existing barriers to biodigester development could help encourage deployment. For example, development of turnkey systems that can be installed by independent third-party operators without significant customization could help in instances where farmers are unfamiliar with digester technology, interconnection requirements and net metering laws. Other measures could include extending the interconnection treatment of wind and solar projects to digesters and simplifying and streamlining the appeals process. Moreover, to prevent gaming by dairies that currently apply their waste to land, it may be helpful to begin with a mandatory reporting program or mandatory participation in a registry.

With respect to the specific design of a cap-and-trade program, a hybrid allowance and credit system probably would work best for the California dairy sector, particularly for the larger dairy operations using liquid management systems. To implement this approach, an estimate of total emissions (and therefore allowances needed) would first be estimated by multiplying livestock population (by type of animal) by average emissions factors. At operations where methane was captured and collected, either for beneficial use or flaring, credits would then be calculated for the emissions reduced.

For smaller farms in particular, transaction costs could be significant. For dairy operations having fewer than 100 head or hog and pig operations having fewer than 500 head, annual emissions would be less than 200 metric tons of CO2-equivalent. On a per-head basis, participation in an emissions trading system for these smaller operations could be quite high, posing a competitive burden. However, California appears to have relatively few small dairy operations, and few (and mostly small) swine operations. Accordingly, excluding these small operations (or allowing them to opt-in to the trading system) would have only a minor effect on total system coverage. Alternatively, or in addition to, a size threshold, a trading system could include only farms within the dairy and swine sub-sectors that use liquid management systems. This would focus on the primary source of emissions, as well as on the types of management systems from which emissions reductions can be obtained.

ATTACHMENT A
MARGINAL ABATEMENT COST CURVES FOR 3 METHANE SECTORS

Tables

1. Natural Gas Systems – Emission Reductions and Break-Even Prices: Year 2010
2. Natural Gas Systems – Emission Reductions and Break-Even Prices: Year 2020
3. Landfills – Emission Reductions and Break-Even Prices: Year 2010
4. Landfills – Emission Reductions and Break-Even Prices: Year 2020
5. Manure Management – Emission Reductions and Break-Even Prices: Year 2010
6. Manure Management – Emission Reductions and Break-Even Prices: Year 2020
7. Three Methane Sectors – Emission Reductions and Break-Even Prices: Year 2010
8. Three Methane Sectors – Emission Reductions and Break-Even Prices: Year 2020

Note: All scenarios assume a discount rate (DR) of 4%, and a tax rate (TR) of 0%.

Source: Developed from ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California*, draft report prepared for the California Energy Commission, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

Table 1: Natural Gas Systems – Emission Reductions and Break-Even Prices (Scenario a-2010) (Year=2010, DR=4%, TR=0%) (developed from Table 10 of ICF July 2005 report)

Sector: ***Nat. Gas***
Baseline tons: ***2.00*** $MMTCO_2e$ in *2010*

Sector	Option	Breakeven Price ($\$/MTCO_2$ Eq.)	Incremental Reductions $MMTCO_2$ Eq.	Incremental Reductions % of Baseline	Sum of Reductions $MMTCO_2$ Eq.	Sum of Reductions % of Baseline
Nat. Gas	P&T-Fuel Gas Retrofit for BD Valve	($8.04)	0.134	6.7%	0.134	6.7%
Nat. Gas	P&T-Reducing the glycol circulation rates in dehydrators (not applicable to Kimray pumps) - Transmission	($7.65)	0.001	0.1%	0.135	6.8%
Nat. Gas	P&T-D I&M (Compressor Stations)	($6.54)	0.009	0.5%	0.144	7.2%
Nat. Gas	Prod-Reducing the glycol circulation rates in dehydrators (not applicable to Kimray pumps)	($6.49)	0.002	0.1%	0.146	7.3%
Nat. Gas	Prod-Replace high-bleed pneumatic devices with low-bleed pneumatic devices	($5.06)	0.070	3.5%	0.216	10.8%
Nat. Gas	P&T-Replace high-bleed pneumatic devices with low-bleed pneumatic devices	($5.06)	0.032	1.6%	0.248	12.4%
Nat. Gas	P&T-Altering start-up Procedures During Maintenance	($4.47)	0.060	3.0%	0.308	15.4%
Nat. Gas	D-D I&M (Distribution)	($4.45)	0.048	2.4%	0.356	17.8%
Nat. Gas	P&T-Installation of Flash Tank Separators Transmission & Storage)	($1.21)	0.002	0.1%	0.358	17.9%
Nat. Gas	D-Electronic Monitoring at Large Surface Facilities	($0.39)	0.108	5.4%	0.466	23.3%
Nat. Gas	P&T-Recip Compressor Rod Packing (Static-Pac)	$7.20	0.025	1.3%	0.491	24.6%
Nat. Gas	Prod-Installation of Flash Tank Separators (Production)	$14.47	0.015	0.8%	0.506	25.3%
Nat. Gas	P&T-Portable Evacuation Compressor for Pipeline Venting	$22.40	0.042	2.1%	0.548	27.4%
Nat. Gas	Prod-Portable Evacuation Compressor for Pipeline Venting	$22.40	0.001	0.0%	0.549	27.4%
Nat. Gas	Prod-D I&M (Pipeline Leaks)	$31.09	0.026	1.3%	0.575	28.7%
Nat. Gas	P&T-D I&M (Wells: Storage)	$38.62	0.002	0.1%	0.577	28.8%
Nat. Gas	Prod-Replace High-bleed pneumatic devices with compressed air systems (Production Only)	$55.39	0.082	4.1%	0.659	32.9%
Nat. Gas	P&T-Replace High-bleed pneumatic devices with compressed air systems (Transmission)	$57.54	0.037	1.9%	0.696	34.8%
Nat. Gas	Prod-Installing Plunger Lift Systems In Gas Wells	$642.61	0.001	0.1%	0.697	34.8%
Nat. Gas	P&T-D I&M (Pipeline: Transmission)	$1,348.07	0.001	0.1%	0.698	34.9%
Nat. Gas	P&T-Surge Vessels for Station/Well Venting	$1,600.08	0.030	1.5%	0.728	36.4%
Nat. Gas	Prod-Surge Vessels for Station/Well Venting	$1,600.08	0.001	0.0%	0.728	36.4%

Source: ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California,* Prepared for the California Energy Commisssion, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

Notes: Prod = production; P&T = processing and transmission; and D = distribution

Table 2: Natural Gas Systems – Emission Reductions and Break-Even Prices (Scenario a-2020) (Year=2020, DR=4%, TR=0%) (developed from Table 11 of ICF July 2005 report)

Sector: ***Nat. Gas***
Baseline tons: ***2.19*** $MMTCO_2e$ in *2020*

Sector	Option	Breakeven Price ($\$/MTCO_2$ Eq.)	Incremental Reductions $MMTCO_2$ Eq.	Incremental Reductions % of Baseline	Sum of Reductions $MMTCO_2$ Eq.	Sum of Reductions % of Baseline
Nat. Gas	P&T-Fuel Gas Retrofit for BD Valve	($7.75)	0.147	6.7%	0.147	6.7%
Nat. Gas	P&T-Reducing the glycol circulation rates in dehydrators (not applicable to Kimray pumps) - Transmission	($7.36)	0.001	0.0%	0.148	6.8%
Nat. Gas	P&T-D I&M (Compressor Stations)	($6.25)	0.010	0.5%	0.158	7.2%
Nat. Gas	Prod-Reducing the glycol circulation rates in dehydrators (not applicable to Kimray pumps)	($6.21)	0.002	0.1%	0.160	7.3%
Nat. Gas	Prod-Replace high-bleed pneumatic devices with low-bleed pneumatic devices	($4.78)	0.077	3.5%	0.237	10.8%
Nat. Gas	P&T-Replace high-bleed pneumatic devices with low-bleed pneumatic devices	($4.78)	0.035	1.6%	0.272	12.4%
Nat. Gas	P&T-Altering start-up Procedures During Maintenance	($4.32)	0.066	3.0%	0.338	15.4%
Nat. Gas	D-D I&M (Distribution)	($4.06)	0.052	2.4%	0.390	17.8%
Nat. Gas	P&T-Installation of Flash Tank Separators Transmission & Storage)	($0.91)	0.003	0.1%	0.393	17.9%
Nat. Gas	D-Electronic Monitoring at Large Surface Facilities	$0.00	0.118	5.4%	0.511	23.3%
Nat. Gas	P&T-Recip Compressor Rod Packing (Static-Pac)	$7.49	0.027	1.2%	0.538	24.6%
Nat. Gas	Prod-Installation of Flash Tank Separators (Production)	$14.76	0.016	0.7%	0.554	25.3%
Nat. Gas	P&T-Portable Evacuation Compressor for Pipeline Venting	$22.70	0.046	2.1%	0.600	27.4%
Nat. Gas	Prod-Portable Evacuation Compressor for Pipeline Venting	$22.70	0.001	0.0%	0.601	27.4%
Nat. Gas	Prod-D I&M (Pipeline Leaks)	$31.37	0.028	1.3%	0.629	28.7%
Nat. Gas	P&T-D I&M (Wells: Storage)	$38.91	0.002	0.1%	0.631	28.8%
Nat. Gas	Prod-Replace High- bleed pneumatic devices with compressed air systems (Production Only)	$55.67	0.090	4.1%	0.721	32.9%
Nat. Gas	P&T-Replace High- bleed pneumatic devices with compressed air systems (Transmission)	$57.83	0.040	1.8%	0.761	34.7%
Nat. Gas	Prod-Installing Plunger Lift Systems In Gas Wells	$642.89	0.001	0.0%	0.762	34.8%
Nat. Gas	P&T-D I&M (Pipeline: Transmission)	$1,348.36	0.001	0.0%	0.763	34.8%
Nat. Gas	P&T-Surge Vessels for Station/Well Venting	$1,600.37	0.033	1.5%	0.796	36.3%
Nat. Gas	Prod-Surge Vessels for Station/Well Venting	$1,600.37	0.001	0.0%	0.797	36.4%

Source: ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California,* Prepared for the California Energy Commisssion, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

Notes: Prod = production; P&T = processing and transmission; and D = distribution

Table 3: Landfills – Emission Reductions and Break-Even Prices (Scenario a-2010) (Year=2010, DR=4%, TR=0%) (developed from Table 18 of ICF July 2005 report)

Sector: ***Landfills***
Baseline tons: ***10.64*** $MMTCO_2e$ in *2010*

Sector	Option	Breakeven Price ($/$MTCO_2$ Eq.)	Incremental Reductions $MMTCO_2$ Eq.	Incremental Reductions % of Baseline	Sum of Reductions $MMTCO_2$ Eq.	Sum of Reductions % of Baseline
Landfills	Direct Gas Use, WIP 1,000,000+ short tons	($4.68)	1.190	11.2%	1.190	11.2%
Landfills	Direct Gas Use, WIP 500,001-1,000,000 short tons	($3.98)	0.610	5.7%	1.800	16.9%
Landfills	Direct Gas Use, WIP 400,001-500,000 short tons	($2.32)	0.350	3.3%	2.150	20.2%
Landfills	Direct Gas Use, WIP 300,001-400,000 short tons	($2.10)	0.120	1.1%	2.270	21.3%
Landfills	Direct Gas Use, WIP 200,001-300,000 short tons	($1.39)	0.001	0.0%	2.271	21.3%
Landfills	Electricity, WIP 1,000,000+ short tons	$0.26	2.690	25.3%	4.961	46.6%
Landfills	Direct Gas Use, WIP 100,001-200,000 short tons	$0.69	0.001	0.0%	4.961	46.6%
Landfills	Electricity, WIP 500,001- 1,000,000 short tons	$1.04	1.510	14.2%	6.471	60.8%
Landfills	Electricity, WIP 400,001- 500,000 short tons	$2.66	0.350	3.3%	6.821	64.1%
Landfills	Electricity, WIP 300,001- 400,000 short tons	$2.87	0.240	2.3%	7.061	66.4%
Landfills	Electricity, WIP 200,001- 300,000 short tons	$3.39	0.400	3.8%	7.461	70.1%
Landfills	Electricity, WIP 100,001- 200,000 short tons	$5.47	0.340	3.2%	7.801	73.3%
Landfills	Direct Gas Use, WIP <100,001 short tons	$9.48	0.001	0.0%	7.802	73.3%
Landfills	Electricity, WIP <100,001 short tons	$14.03	1.230	11.6%	9.032	84.9%

Source: ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California,* Prepared for the California Energy Commisssion, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

Table 4: Landfills – Emission Reductions and Break-Even Prices (Scenario a-2020) (Year=2020, DR=4%, TR=0%) (developed from Table 18 of ICF July 2005 report)

Sector: ***Landfills***
Baseline tons: ***11.43*** $MMTCO_2e$ in *2020*

Sector	Option	Breakeven Price ($/MTCO$_2$ Eq.)	Incremental Reductions MMTCO$_2$ Eq.	Incremental Reductions % of Baseline	Sum of Reductions MMTCO$_2$ Eq.	Sum of Reductions % of Baseline
Landfills	Direct Gas Use, WIP 1,000,000+ short tons	($4.68)	1.280	11.2%	1.280	11.2%
Landfills	Direct Gas Use, WIP 500,001-1,000,000 short tons	($3.98)	0.650	5.7%	1.930	16.9%
Landfills	Direct Gas Use, WIP 400,001-500,000 short tons	($2.32)	0.380	3.3%	2.310	20.2%
Landfills	Direct Gas Use, WIP 300,001-400,000 short tons	($2.10)	0.130	1.1%	2.440	21.3%
Landfills	Direct Gas Use, WIP 200,001-300,000 short tons	($1.39)	0.001	0.0%	2.441	21.4%
Landfills	Electricity, WIP 1,000,000+ short tons	$0.26	2.890	25.3%	5.331	46.6%
Landfills	Direct Gas Use, WIP 100,001-200,000 short tons	$0.69	0.001	0.0%	5.331	46.6%
Landfills	Electricity, WIP 500,001- 1,000,000 short tons	$1.04	1.630	14.3%	6.961	60.9%
Landfills	Electricity, WIP 400,001- 500,000 short tons	$2.66	0.380	3.3%	7.341	64.2%
Landfills	Electricity, WIP 300,001- 400,000 short tons	$2.87	0.260	2.3%	7.601	66.5%
Landfills	Electricity, WIP 200,001- 300,000 short tons	$3.39	0.430	3.8%	8.031	70.3%
Landfills	Electricity, WIP 100,001- 200,000 short tons	$5.47	0.360	3.1%	8.391	73.4%
Landfills	Direct Gas Use, WIP <100,001 short tons	$9.48	0.001	0.0%	8.392	73.4%
Landfills	Electricity, WIP <100,001 short tons	$14.03	1.320	11.5%	9.712	85.0%

Source: ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California,* Prepared for the California Energy Commisssion, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

Table 5: Manure Management – Emission Reductions and Break-Even Prices (Scenario a-2010) (Year=2010, DR=4%, TR=0%) (developed from Table 29 of ICF July 2005 report)

Sector: ***Manure Mgt.***
Baseline tons: ***8.85*** $MMTCO_2e$ in *2010*

Sector	Option	Breakeven Price ($\$/MTCO_2$ Eq.)	Incremental Reductions $MMTCO_2$ Eq.	Incremental Reductions % of Baseline	Sum of Reductions $MMTCO_2$ Eq.	Sum of Reductions % of Baseline
Manure Mgt.	Covered Lagoon, not including Lagoon - Large Dairy	($3.94)	1.730	19.5%	1.730	19.5%
Manure Mgt.	Covered Lagoon including Lagoon Cost - Large Dairy	($2.21)	0.740	8.4%	2.470	27.9%
Manure Mgt.	Plug Flow Digester - Medium Dairy	($0.61)	0.310	3.5%	2.780	31.4%
Manure Mgt.	2-Stage Plug Flow Digester - Large Dairy	$2.73	0.090	1.0%	2.870	32.4%
Manure Mgt.	Complete Mix Digester - Medium Dairy	$6.00	0.130	1.5%	3.000	33.9%
Manure Mgt.	Covered Lagoon, not including Lagoon Cost - Small Dairy	$8.81	1.730	19.5%	4.730	53.4%
Manure Mgt.	Centralized Digester	$9.54	0.330	3.7%	5.060	57.2%
Manure Mgt.	Covered Lagoon including Lagoon Cost - Small Dairy	$14.78	0.740	8.4%	5.800	65.5%

Source: ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California,* Prepared for the California Energy Commisssion, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

Table 6: Manure Management – Emission Reductions and Break-Even Prices (Scenario a-2020) (Year=2020, DR=4%, TR=0%) (developed from Table 30 of ICF July 2005 report)

Sector: ***Manure Mgt.***
Baseline tons: ***9.54*** $MMTCO_2e$ in *2020*

Sector	Option	Breakeven Price ($/$MTCO_2$ Eq.)	Incremental Reductions $MMTCO_2$ Eq.	Incremental Reductions % of Baseline	Sum of Reductions $MMTCO_2$ Eq.	Sum of Reductions % of Baseline
Manure Mgt.	Covered Lagoon, not including Lagoon - Large Dairy	($3.94)	1.860	19.5%	1.860	19.5%
Manure Mgt.	Covered Lagoon including Lagoon Cost - Large Dairy	($2.21)	0.800	8.4%	2.660	27.9%
Manure Mgt.	Plug Flow Digester - Medium Dairy	($0.61)	0.330	3.5%	2.990	31.3%
Manure Mgt.	2-Stage Plug Flow Digester - Large Dairy	$2.73	0.090	0.9%	3.080	32.3%
Manure Mgt.	Complete Mix Digester - Medium Dairy	$6.00	0.140	1.5%	3.220	33.8%
Manure Mgt.	Covered Lagoon, not including Lagoon Cost - Small Dairy	$8.81	1.860	19.5%	5.080	53.2%
Manure Mgt.	Centralized Digester	$9.54	0.360	3.8%	5.440	57.0%
Manure Mgt.	Covered Lagoon including Lagoon Cost - Small Dairy	$14.78	0.800	8.4%	6.240	65.4%

Source: ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California,* Prepared for the California Energy Commisssion, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

Table 7: Three Methane Sectors – Emission Reductions and Break-Even Prices (Scenario a-2010) (Year=2010, DR=4%, TR=0%) (developed from Tables 10, 18, and 29 of ICF July 2005 report)

Baseline tons: Sector	$MMTCO_2e$ in 2020
Natural Gas	2.00
Manure Mgt.	8.85
Landfills	10.64
Total	21.49

Sector	Option	Breakeven Price ($\$/MTCO_2$ Eq.)	Incremental Reductions $MMTCO_2$ Eq.	Incremental Reductions % of Baseline	Sum of Reductions $MMTCO_2$ Eq.	Sum of Reductions % of Baseline
Nat. Gas	P&T-Fuel Gas Retrofit for BD Valve	($8.04)	0.134	0.6%	0.134	0.6%
Nat. Gas	P&T-Reducing the glycol circulation rates in dehydrators (not applicable to Kimray pumps) - Transmission	($7.65)	0.001	0.0%	0.135	0.6%
Nat. Gas	P&T-D I&M (Compressor Stations)	($6.54)	0.009	0.0%	0.144	0.7%
Nat. Gas	Prod-Reducing the glycol circulation rates in dehydrators (not applicable to Kimray pumps)	($6.49)	0.002	0.0%	0.146	0.7%
Nat. Gas	P&T-Replace high-bleed pneumatic devices with low-bleed pneumatic devices	($5.06)	0.032	0.1%	0.178	0.8%
Nat. Gas	Prod-Replace high-bleed pneumatic devices with low-bleed pneumatic devices	($5.06)	0.070	0.3%	0.248	1.2%
Landfills	Direct Gas Use, WIP 1,000,000+ short tons	($4.68)	1.190	5.5%	1.438	6.7%
Nat. Gas	P&T-Altering start-up Procedures During Maintenance	($4.47)	0.060	0.3%	1.498	7.0%
Nat. Gas	D-D I&M (Distribution)	($4.45)	0.048	0.2%	1.546	7.2%
Landfills	Direct Gas Use, WIP 500,001-1,000,000 short tons	($3.98)	0.610	2.8%	2.156	10.0%
Manure Mgt.	Covered Lagoon, not including Lagoon - Large Dairy	($3.94)	1.730	8.1%	3.886	18.1%
Landfills	Direct Gas Use, WIP 400,001-500,000 short tons	($2.32)	0.350	1.6%	4.236	19.7%
Manure Mgt.	Covered Lagoon including Lagoon Cost - Large Dairy	($2.21)	0.740	3.4%	4.976	23.2%
Landfills	Direct Gas Use, WIP 300,001-400,000 short tons	($2.10)	0.120	0.6%	5.096	23.7%
Landfills	Direct Gas Use, WIP 200,001-300,000 short tons	($1.39)	0.001	0.0%	5.097	23.7%
Nat. Gas	P&T-Installation of Flash Tank Separators Transmission & Storage)	($1.21)	0.002	0.0%	5.099	23.7%
Manure Mgt.	Plug Flow Digester - Medium Dairy	($0.61)	0.310	1.4%	5.409	25.2%
Nat. Gas	D-Electronic Monitoring at Large Surface Facilities	($0.39)	0.108	0.5%	5.517	25.7%
Landfills	Electricity, WIP 1,000,000+ short tons	$0.26	2.690	12.5%	8.207	38.2%
Landfills	Direct Gas Use, WIP 100,001-200,000 short tons	$0.69	0.001	0.0%	8.207	38.2%
Landfills	Electricity, WIP 500,001- 1,000,000 short tons	$1.04	1.510	7.0%	9.717	45.2%
Landfills	Electricity, WIP 400,001- 500,000 short tons	$2.66	0.350	1.6%	10.067	46.8%
Manure Mgt.	2-Stage Plug Flow Digester - Large Dairy	$2.73	0.090	0.4%	10.157	47.3%
Landfills	Electricity, WIP 300,001- 400,000 short tons	$2.87	0.240	1.1%	10.397	48.4%
Landfills	Electricity, WIP 200,001- 300,000 short tons	$3.39	0.400	1.9%	10.797	50.2%
Landfills	Electricity, WIP 100,001- 200,000 short tons	$5.47	0.340	1.6%	11.137	51.8%
Manure Mgt.	Complete Mix Digester - Medium Dairy	$6.00	0.130	0.6%	11.267	52.4%
Nat. Gas	P&T-Recip Compressor Rod Packing (Static-Pac)	$7.20	0.025	0.1%	11.292	52.5%
Manure Mgt.	Covered Lagoon, not including Lagoon Cost - Small Dairy	$8.81	1.730	8.1%	13.022	60.6%
Landfills	Direct Gas Use, WIP <100,001 short tons	$9.48	0.001	0.0%	13.023	60.6%
Manure Mgt.	Centralized Digester	$9.54	0.330	1.5%	13.353	62.1%
Landfills	Electricity, WIP <100,001 short tons	$14.03	1.230	5.7%	14.583	67.9%
Nat. Gas	Prod-Installation of Flash Tank Separators (Production)	$14.47	0.015	0.1%	14.598	67.9%
Manure Mgt.	Covered Lagoon including Lagoon Cost - Small Dairy	$14.78	0.740	3.4%	15.338	71.4%
Nat. Gas	P&T-Portable Evacuation Compressor for Pipeline Venting	$22.40	0.042	0.2%	15.380	71.6%
Nat. Gas	Prod-Portable Evacuation Compressor for Pipeline Venting	$22.40	0.001	0.0%	15.380	71.6%
Nat. Gas	Prod-D I&M (Pipeline Leaks)	$31.09	0.026	0.1%	15.406	71.7%
Nat. Gas	P&T-D I&M (Wells: Storage)	$38.62	0.002	0.0%	15.408	71.7%
Nat. Gas	Prod-Replace High-bleed pneumatic devices with compressed air systems (Production Only)	$55.39	0.082	0.4%	15.490	72.1%
Nat. Gas	P&T-Replace High-bleed pneumatic devices with compressed air systems (Transmission)	$57.54	0.037	0.2%	15.527	72.3%
Nat. Gas	Prod-Installing Plunger Lift Systems In Gas Wells	$642.61	0.001	0.0%	15.528	72.3%
Nat. Gas	P&T-D I&M (Pipeline: Transmission)	$1,348.07	0.001	0.0%	15.529	72.3%
Nat. Gas	P&T-Surge Vessels for Station/Well Venting	$1,600.08	0.030	0.1%	15.559	72.4%
Nat. Gas	Prod-Surge Vessels for Station/Well Venting	$1,600.08	0.001	0.0%	15.560	72.4%

Source: ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California,* Prepared for the California Energy Commisssion, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

Notes: Prod = production; P&T = processing and transmission; and D = distribution

Table 8: Three Methane Sectors – Emission Reductions and Break-Even Prices (Scenario a-2020) (Year=2020, DR=4%, TR=0%) (developed from Tables 10, 18, and 30 of ICF July 2005 report)

Baseline tons:	**Sector**	$MMTCO_2e$ in 2020
	Natural Gas	**2.19**
	Manure Mgt.	**9.54**
	Landfills	**11.43**
	Total	**23.16**

Sector	Option	Breakeven Price ($/$MTCO_2$ Eq.)	Incremental Reductions $MMTCO_2$ Eq.	Incremental Reductions % of Baseline	Sum of Reductions $MMTCO_2$ Eq.	Sum of Reductions % of Baseline
Nat. Gas	P&T-Fuel Gas Retrofit for BD Valve	($7.75)	0.147	0.6%	0.147	0.6%
Nat. Gas	P&T-Reducing the glycol circulation rates in dehydrators (not applicable to Kimray pumps) - Transmission	($7.36)	0.001	0.0%	0.148	0.6%
Nat. Gas	P&T-D I&M (Compressor Stations)	($6.25)	0.010	0.0%	0.158	0.7%
Nat. Gas	Prod-Reducing the glycol circulation rates in dehydrators (not applicable to Kimray pumps)	($6.21)	0.002	0.0%	0.160	0.7%
Nat. Gas	P&T-Replace high-bleed pneumatic devices with low-bleed pneumatic devices	($4.78)	0.035	0.2%	0.195	0.8%
Nat. Gas	Prod-Replace high-bleed pneumatic devices with low-bleed pneumatic devices	($4.78)	0.077	0.3%	0.272	1.2%
Landfills	Direct Gas Use, WIP 1,000,000+ short tons	($4.68)	1.280	5.5%	1.552	6.7%
Nat. Gas	P&T-Altering start-up Procedures During Maintenance	($4.32)	0.066	0.3%	1.618	7.0%
Nat. Gas	D-D I&M (Distribution)	($4.06)	0.052	0.2%	1.670	7.2%
Landfills	Direct Gas Use, WIP 500,001-1,000,000 short tons	($3.98)	0.650	2.8%	2.320	10.0%
Manure Mgt.	Covered Lagoon, not including Lagoon - Large Dairy	($3.94)	1.860	8.0%	4.180	18.0%
Landfills	Direct Gas Use, WIP 400,001-500,000 short tons	($2.32)	0.380	1.6%	4.560	19.7%
Manure Mgt.	Covered Lagoon including Lagoon Cost - Large Dairy	($2.21)	0.800	3.5%	5.360	23.1%
Landfills	Direct Gas Use, WIP 300,001-400,000 short tons	($2.10)	0.130	0.6%	5.490	23.7%
Landfills	Direct Gas Use, WIP 200,001-300,000 short tons	($1.39)	0.001	0.0%	5.491	23.7%
Nat. Gas	P&T-Installation of Flash Tank Separators Transmission & Storage)	($0.91)	0.003	0.0%	5.494	23.7%
Manure Mgt.	Plug Flow Digester - Medium Dairy	($0.61)	0.330	1.4%	5.824	25.1%
Nat. Gas	D-Electronic Monitoring at Large Surface Facilities	$0.00	0.118	0.5%	5.942	25.7%
Landfills	Electricity, WIP 1,000,000+ short tons	$0.26	2.890	12.5%	8.832	38.1%
Landfills	Direct Gas Use, WIP 100,001-200,000 short tons	$0.69	0.001	0.0%	8.832	38.1%
Landfills	Electricity, WIP 500,001- 1,000,000 short tons	$1.04	1.630	7.0%	10.462	45.2%
Landfills	Electricity, WIP 400,001- 500,000 short tons	$2.66	0.380	1.6%	10.842	46.8%
Manure Mgt.	2-Stage Plug Flow Digester - Large Dairy	$2.73	0.090	0.4%	10.932	47.2%
Landfills	Electricity, WIP 300,001- 400,000 short tons	$2.87	0.260	1.1%	11.192	48.3%
Landfills	Electricity, WIP 200,001- 300,000 short tons	$3.39	0.430	1.9%	11.622	50.2%
Landfills	Electricity, WIP 100,001- 200,000 short tons	$5.47	0.360	1.6%	11.982	51.7%
Manure Mgt.	Complete Mix Digester - Medium Dairy	$6.00	0.140	0.6%	12.122	52.3%
Nat. Gas	P&T-Recip Compressor Rod Packing (Static-Pac)	$7.49	0.027	0.1%	12.149	52.5%
Manure Mgt.	Covered Lagoon, not including Lagoon Cost - Small Dairy	$8.81	1.860	8.0%	14.009	60.5%
Landfills	Direct Gas Use, WIP <100,001 short tons	$9.48	0.001	0.0%	14.010	60.5%
Manure Mgt.	Centralized Digester	$9.54	0.360	1.6%	14.370	62.0%
Landfills	Electricity, WIP <100,001 short tons	$14.03	1.320	5.7%	15.690	67.7%
Nat. Gas	Prod-Installation of Flash Tank Separators (Production)	$14.76	0.016	0.1%	15.706	67.8%
Manure Mgt.	Covered Lagoon including Lagoon Cost - Small Dairy	$14.78	0.800	3.5%	16.506	71.3%
Nat. Gas	P&T-Portable Evacuation Compressor for Pipeline Venting	$22.70	0.046	0.2%	16.552	71.5%
Nat. Gas	Prod-Portable Evacuation Compressor for Pipeline Venting	$22.70	0.001	0.0%	16.553	71.5%
Nat. Gas	Prod-D I&M (Pipeline Leaks)	$31.37	0.028	0.1%	16.581	71.6%
Nat. Gas	P&T-D I&M (Wells: Storage)	$38.91	0.002	0.0%	16.583	71.6%
Nat. Gas	Prod-Replace High- bleed pneumatic devices with compressed air systems (Production Only)	$55.67	0.090	0.4%	16.673	72.0%
Nat. Gas	P&T-Replace High- bleed pneumatic devices with compressed air systems (Transmission)	$57.83	0.040	0.2%	16.713	72.2%
Nat. Gas	Prod-Installing Plunger Lift Systems In Gas Wells	$642.89	0.001	0.0%	16.714	72.2%
Nat. Gas	P&T-D I&M (Pipeline: Transmission)	$1,348.36	0.001	0.0%	16.715	72.2%
Nat. Gas	P&T-Surge Vessels for Station/Well Venting	$1,600.37	0.033	0.1%	16.748	72.3%
Nat. Gas	Prod-Surge Vessels for Station/Well Venting	$1,600.37	0.001	0.0%	16.748	72.3%

Source: ICF Consulting, *Emission Reduction Opportunities for Non-CO_2 Gases in California,* Prepared for the California Energy Commisssion, Public Interest Energy Research Program, July 2005, Report No. CEC-500-2005-121.

Notes: Prod = production; P&T = processing and transmission; and D = distribution